RESERVOIR ENGINEERING ASPECTS AND RESOURCE ASSESSMENT METHODOLOGY OF EASTERN DEVONIAN GAS SHALES

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Prepared for the

United States Department of Energy
Morgantown Energy Technology Center
Eastern Gas Shales Project

Under Contract No. EY-78-C-21-8216

October 5, 1978

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ABSTRACT

The U.S. Department of Energy's Morgantown Energy Technology Center (METC) and Science Applications, Inc., are cooperating in the characterization of the Eastern Devonian Shale gas resource. This study, focusing on the Lincoln County, WV, area, characterizes the resource and shows that conventional volumetric techniques cannot be used to determine the amount of gas in place.

Previous studies, using calculations based on limited offgassing measurements and volumetric information, have indicated that the resource ranges from 500 TCF to 2400 TCF of gas in place. The volumetric method based on fracture porosity data yields low values; offgassing measurements can be used to determine gas in place if sufficient time is allowed for gas to sorb from the shale matrix.

Production-pressure decline curves are presented for several wells to show the effect of sorption on cumulative production.

A mathematical model for describing the behavior of a dual-porosity gas reservoir is presented. It shows the effect of sorption on the production behavior of the gas reservoir. It is concluded that the early part of production behavior is controlled by free gas in the fractures, while long-time behavior is controlled by sorption-diffusion mechanisms.

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INTRODUCTION

The two main objectives of this study are: to provide a resource characterization of gas reserves in the Eastern Devonian Shales, and to plan and initiate a long-term reservoir engineering program to permit the most economical development of the Devonian Shales. This report presents information developed to meet the first objective.

Previous studies[1,2] showed that the gas resource of the Devonian Shales has been estimated at from 500 TCF to 2400 TCF of gas in place. The authors believed that the estimates varied because the character of Devonian Shale was not understood and information about the nature of the porous shale formation was not available. Thus, this study has focused on the following areas.

All available information concerning the formation was reviewed, including published geological studies and well files of Morgantown Energy Technology Center (METC) and Eastern Gas Shale Project (EGSP) contractors, particularly Columbia Gas System. Some of these files contained valuable information on periodic production tests and measurement of pressures in specific wells. Well log data, rock properties, and offgassing information were collected and organized. This information was inspected and analyzed as to reliability. Conclusions were reached in regard to the nature of the reservoir. A pilot reservoir engineering study was conducted for the Lincoln County, WV, area (Area 4 in Figure 1). A dual-porosity mathematical model is presented showing the unconventional nature of the Devonian Shales. This model is one of a class of models that has been useful in analyzing the behavior of Devonian Shale gas reservoirs affected by sorption.

RESOURCE

Structure

Lincoln County, WV, is located in the central portion of the Appalachian Plateau Province and is characterized by numerous small synclines that together form a broad, elongated synclinorium. In the area of Lincoln County, these synclines are less apparent and the most prominent surface structural feature is the Guthrie Syncline at the southern end of the county.[5] Detailed information on the subsurface structure is not available due to the lack of sufficient deep wells in the area.

A zone of deep-seated faulting[6] has been postulated as a major mechanism in producing fracture systems and fracture porosities in the Devonian Shales in areas of southwestern West Virginia that historically have produced gas from the Devonian Shales.[7,8,9] The major basement structural feature that may underlie Lincoln County is the Rome Trough (Figure 2).[10] Recent studies of the Cottageville Gas Field in Jackson and Mason Counties, WV, located approximately 80 miles northeast of the study area, suggest that movement of the basement fault blocks in the Rome Trough has resulted in the fracturing observed in the Devonian Shales.[9,11] Insufficient deep structural data on Lincoln County preclude hypothesizing, at this time, that similar basement movements caused the fracturing observed in cores from Columbia Wells #20402 and #20403, although a preliminary inspection of the data suggests similar directional trends of fractures and postulated strike of the basement faults in both areas. The dominant fracture trend, based on these two wells, strikes northeast.[12] Studies of the Cottageville Field show a similar northeast fracture trend but the orientations are more dispersed. DeWys and Shumaker[9] show that the trends appear to approximate the postulated strike of the basement faulting.

Stratigraphy

The Devonian Shale sequence is defined as those lithologic units located below the base of the Berea Sandstone (Lower Mississippian) and above the top of the Onondaga (Corniferous) Limestone (Lower Middle Devonian). The total Devonian Shale interval in this area is approximately 1400 feet. A stratigraphic section of the interval for the area is presented in Figure 3.[12,13] The rock unit names are based on accepted New York and Ohio nomenclature. For the purpose of this study, to avoid incorrect correlations of accepted stratigraphic units, six shale horizons are identified in the Lincoln County wells (Figure 4).[12,15] These units are (1) Upper Gray, which is silty and medium gray to greenish gray in color; (2) Upper Brown--mostly dark gray with higher organic content than the Upper Gray; (3) Middle Gray--medium to dark gray with higher carbon content than the Upper Gray; (4) Middle Brown--black with medium gray zones and high carbon content; (5) Lower Gray--blue gray with black layers; and (6) Lower Brown--black and similar in content to the Middle Brown (Figure 5).[16]

Geochemical and Geophysical Characteristics

Within an area or specific well, positive correlations exist between gas content and carbon. Between wells in different areas, thermal maturity affects the carbon to gas relationship. Thermal maturity in the Devonian Shales appears to be controlled by geographic position as the range of values for a single well does not change significantly with depth. There would be no significant difference in thermal maturity for the three wells in Area 4.

Data on gas content as derived from measurement of gas release from encapsulated samples are provided to the EGSP by Battelle Columbus Laboratories, Mound Facility, and Columbia Gas System. Battelle Columbus Laboratories and Columbia Gas System provided data on the wells in Area 4. There is a difference in analytical methodology between these two organizations. Columbia Gas System begins to take pressure/volume readings as soon as pressure begins to build in the containers, whereas Battelle Columbus Laboratories, and Mound Facility, allow the sample to equilibrate for three weeks before the first measurements are made. Columbia Gas System also uses a multiplication factor of 1.3 to allow for gas lost prior to encapsulation of the sample.[16]

Even with the difference in technique, data from both Battelle Columbus Laboratories and Columbia Gas System indicate the same relatively high and low gas content zones in the cores from Area 4. Outgas data can be used to indicate stratigraphic horizons that are high in gas relative to other horizons, or areas that are high in gas relative to other areas. Only a conservative number can be placed on the gas resource at this time from outgas data because of unknown variables.

These unknown variables include (1) loss of gas prior to encapsulation; (2) loss of gas due to container leakage; and (3) gas that would be released over a long period of time. All gas held in fracture porosity would be released prior to encapsulation of the samples. In a highly fractured sample, the 1.3 multiplication factor used by Columbia Gas System may be very conservative. Substantial losses of gas due to container leakage are not uncommon. Numerous reports of swollen and burst containers have been received. There is a significant amount of gas released from the shale after the three-week equilibration period. Chase[17] reports that between the third and eleventh weeks on samples from the Monongalia County, WV, well, an additional 15-30 percent gas volume was measured in the containers. Battelle Columbus Laboratories[18] reports that gas volume of the samples tested from the Mason County, WV, well increased from 40-150 percent between the third and eleventh weeks. These data indicate that the gas content of the shale as derived by offgas measurements is extremely conservative. The total gas content appears to be considerably higher and after results of the time relationship are compiled, these figures may be several times too low.

Data presented in Figures 6 and 7 compare the gamma ray measurement with lithology, porosity, carbon content, and permeability. No conclusive trends can be identified for the basin with these limited data; however, higher offgassing values were observed in rich organic black shale sections with relatively higher porosities. Zones indicating low gas release have lower carbon content and lower porosities. In these wells there appears to be a triaxial relationship among these three parameters. The porosities in these wells generally increase with depth and the basal zone corresponding to the Lower Brown unit releases relatively large quantities of gas. This zone of high organic content and high offgas values shows up consistently in wells in other parts of the Appalachian Basin. This data can be used to determine which zones are high in gas content, but not necessarily high in gas production. Permeability measurements throughout the shale are low unless fractures are encountered.

RESERVOIR ASPECTS

Rock Properties

The physical properties of the Devonian Shales such as permeability, porosity, water saturation, etc., are tabulated (Tables 1-3) by zones for Wells #20401, #20402, and #20403 in Lincoln County, WV. The values represent the best available information of any area, although large gaps in information are apparent over the intervals. Therefore, the data are not sufficient to make a complete engineering analysis and are supplemented by using data on known shale characteristics.

Based on field observations, laboratory measurements, and general character of shales, it is recognized that the Devonian Shale exhibits two types of porosity, described as follows:

(a) Primary porosity (matrix porosity) is intergranular and controlled by deposition and lithification. It is largely dependent on the geometry, size distribution, and spatial distribution of the grains. Shales exhibit very low primary porosity.[19]

(b) Secondary porosity (fracture porosity) is controlled by fracturing and jointing resulting from failure during mechanical deformation. This independent network of secondary porosity is superimposed on the very low primary porosity. After deformation of the shale, some of the fractures may close because of the elastic properties of shales. This increases the degree of heterogeneity of the formation.

Primary fractures generally exhibit a dominant trend in a single direction and may exhibit anisotropic permeability which is described mathematically by symmetric tensors or maximum and minimum permeabilities oriented 90° apart. Observations in the field indicate a similar trend. The predominant strike of vertical fractures as determined by Morgantown Energy Technology Center (METC) on core samples from Well #20403 is N60-90°E.[20] This trend was observed throughout the entire section. At a well depth of 3000 feet some fractures also strike N40°W and at depths below 3500 feet a set of fractures trends N75°W.

At depth, fractures that were created during stress conditions may have later sealed after release of the stress. Most fractures are only a fraction of a millimeter wide. With a compressive stress of 600 kg/cm^2 at a depth of 1 km, flow can be expected in shales.[21] An open tension joint or fracture cannot exist at depth except under specific conditions and must be filled by an intruded foreign rock or a recrystallized component of the surrounding rock.[22] In the Devonian Shale, fractures are normally filled with either carbonate or pyritic material.

Spacing of the fractures is variable, but fractures may occur close enough together so that two or more often intersect in a 6-inch well bore.[23]

Gas in Place

As previously stated, it is not possible to estimate the gas resource for the entire Appalachian Basin using currently available data. Therefore, the nature of the gas resource in the Devonian Shale will be discussed in this section.

It is believed that gas is held in the Devonian Shale in two ways:[24] (1) As a free gas within the fractures (secondary porosity) and (2) as sorbed gas within the matrix of the shale (primary porosity). The conventional volumetric method, which does not include sorbed gas in estimation of gas in place, cannot be used to determine the Devonian Shale gas resource.

Offgassing measurements, if continued until the gas is sorbed from the matrix, can be used to calculate gas in place. Offgassing values are subject to the following limitations: (1) Only a fraction of the moveable gas may actually be measured; (2) Offgas values represent the short period of encapsulation; preliminary long-term depletion of encapsulated samples indicates much larger volumes of gas released.[18]

Based on offgassing measurements for Well #20403, gas in place was calculated for a 150-acre spacing. Gas in place based on the volumetric method was also calculated for comparison of the two methods, although the figure is conservative because of the variables discussed previously. Table 4 shows gas in place based on offgassing data to be 2×10^9 SCF and gas in place based on volumetric data to be 0.8×10^9 SCF. The fact that offgassing data yields higher values is probably due to sorbed gas. Further studies of gas sorption in shale are needed to clarify this discrepancy.

Porosity data for volumetric calculations were generated by Core Laboratories, Inc., and Battelle Columbus Laboratories.[16] The gas saturation value used was an average of 45 percent[28] over the entire interval. This value is questionable since core measurements indicated no producible water based on centrifugal measurements.

Production Performance

In order to investigate the possibility that long-time production behavior is affected by the sorption process, a conceptual model was developed. Figure 8 represents the gas sorption curve for this conceptual model of a bounded dual porosity reservoir.[26] At some value of pressure p_L, the slope $(\frac{\partial c}{\partial p})$ of the sorption curve becomes zero. In other words, the diffusion rate from the shale matrix into the fractures is zero if the reservoir pressure is greater than the p_L. Thus, the early part of cumulative production is basically from free gas within the fractures. When the reservoir pressure drops lower than p_L, gas starts to diffuse from the shale matrix into the fractures.

Figure 9 presents the typical behavior of this conceptual reservoir. The first part of this curve is a straight line that when extrapolated to a pressure of zero yields the initial volume of free gas in fractures. Sorption of gas causes a bending of this straight line upwards.

Figures 10 and 11 present p/z versus cumulative production from wells #6630 and #6654 in Lincoln County, WV. Early production is characterized by a straight line depletion and the extrapolation of the lines yields initial gas in place of 138 MMSCF and 108 MMSCF, respectively. During the latter part of production the curve starts to deviate from the line, indicating a slower decline. This behavior of actual field data is very similar to the conceptual model discussed earlier. Calculation of initial gas in place would require the use of a sorption curve for the particular reservoir.

This behavior can be seen in other parts of the basin. Figures 12 and 13 show the p/z versus cumulative production for two wells in Meigs County, OH. The initial free gas in these two wells is about 60 MMSCF, even though the initial pressures in this area are higher than those in Lincoln County.

A dual porosity model[29] (Appendix A) was also developed to investigate the behavior of the Devonian Shales. The purpose of the model was to demonstrate that the mechanism of sorption-diffusion could be used to explain the deviation from volumetric reservoir behavior in the absence of a water drive. Data used for the model, which was run for 15 years, are presented in Table 5. Two cases were considered in this 15-year reservoir study:

(1) No sorption considered, as a single porosity model;
(2) Sorption considered, as a dual porosity model.

Figure 14 shows a graph of p_{avg}/z_{avg} versus the cumulative production. It is apparent that if sorption-diffusion is ignored and no active water drive exists, a plot of p_{avg}/z_{avg} versus cumulative production yields a straight line, which is characteristic of volumetric gas reservoirs. On the other hand, if the sorption-diffusion mechanism is implied in the absence of a water drive, the p_{avg}/z_{avg} versus cumulative production curve deviates from the volumetric reservoir case. <u>This behavior indicates that conventional reservoir analysis methods may not be applicable to Devonian Shale formations.</u>

Figure 15 shows the effect of sorption on the production rate. During the early life of the reservoir, most production is from free gas within the fractures. The production rate is doubled in the latter production life of the well due to gas sorption from the matrix. A small effect of sorption on production rate can be seen in the early life of the reservoir because the initial reservoir pressure was lower than p_L. Figure 16 shows the effect of sorption on cumulative production.

Future uses of this model will include the history-matching of the drawdown, buildup tests, and production data to determine reservoir parameters.

CONCLUSIONS AND RECOMMENDATIONS

(1) The dual porosity model is representative of the Devonian Shale reservoir.

(2) Estimates of gas in place based on offgassing calculations indicate larger values than those based on the volumetric method.

(3) Gas in place cannot be determined from the production-pressure decline data. However, it may indicate that initial free gas is present within the fractures.

(4) The volumetric behavior of the field data can be explained with the sorption mechanism.

(5) The sorption model indicates much higher production rates in the latter part of production and larger cumulative production than does the volumetric method.

In order to determine the gas resources and reserves of the Devonian Shale, the following are recommended:

(1) Heterogeneity and anisotropy of the field must be determined by means of interference tests, well testing, and laboratory measurements in order to have a meaningful reservoir model.

(2) Producing rates and pressures should be measured on a daily basis. Shut-in times and starting times of production should also be recorded.

(3) Static formation pressure should be measured at the wells on at least an annual basis.

(4) Sorption and pressure relationships must be determined for the major Devonian Shale gas fields.

(5) Diffusion constants must be determined for shale samples from the major Devonian Shale gas fields.

NOMENCLATURE

a	Radius of shale particle, cm
C	Concentration, g mole/cm^3
D	Diffusivity, cm^2/sec
g	Acceleration of gravity, cm/sec^2
k	Permeability
k_{rw}	Relative permeability to water
k_{rg}	Relative permeability to gas
M_w	Molecular weight
N_v	Rate of methane desorption per unit matrix volume, g/cm^2-sec
p	Pressure
p_{avg}	Average reservoir pressure, psia
p_{ws}	Static well pressure, psia
p_{wf}	Flowing well pressure, psia
p_g	Pressure of gas phase
p_w	Pressure of water phase
p_L	Upper limit pressure after which sorption does not occur
$(\frac{\partial c}{\partial p})$	The slope of the sorption curve
q	Production rate, SCFD
r	Radius
S_g	Gas saturation
S_w	Water saturation
t	Time
ϕ	Porosity
ρ_g	Density of gas
ρ_w	Density of water
μ_g	Viscosity of gas
μ_w	Viscosity of water
z	Compressibility factor
z_{avg}	Average compressibility factor

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ACKNOWLEDGEMENT

The authors acknowledge the valuable contributions made towards this study by Science Applications, Inc., Morgantown, WV, staff members Douglas Terry, George Fingleton, John Curtis, Christopher Pulle, and William G. McGlade. We thank Mr. Robert Chase, Marietta College, for providing the numerical model used in this paper.

We also acknowledge the aid and encouragement given by Mr. Charles A. Komar, Assistant Project Manager of the Eastern Gas Shales Project at DOE Morgantown Energy Technology Center (METC) and the various EGSP contractors, particularly Columbia Gas System, in allowing access to their well records.

APPENDIX A

Mathematical Model for the Dual Porosity Gas Reservoir

The dual porosity mathematical model was originally developed by Price and Ancell[30] for the investigation of the feasibility of methane flow in coal and was subsequently adapted for use in the Devonian Shale.[31] A similar model by Chase[29] was adapted by SAI for this study. The following is a brief description of the dual porosity model.

The basic equations describing the flow of gas and water in a fractured porous medium are:

$$\nabla \cdot \left[\frac{\rho_w k k_{rw}}{\mu_w} (\nabla p_w - \rho_w g \nabla h) \right] - q_{wv} = \frac{\partial}{\partial t}(\phi \rho_w S_w) \qquad \text{(A-1)}$$

$$\nabla \cdot \left[\frac{\rho_g k k_{rg}}{\mu_g} (\nabla p_g - \rho_g g \nabla h) \right] + N_v - q_{gv} = \frac{\partial}{\partial t} (\phi \rho_g S_g) \qquad \text{(A-2)}$$

Since it is known that only gas and water exist in the system,

$$S_g + S_w = 1 \qquad \text{(A-3)}$$

The capillary pressure at any point in the system is defined as:

$$p_c = p_g + p_w \qquad \text{(A-4)}$$

The gas desorption term, N_v, in equation A-2, is determined utilizing the solution of the diffusion equation for the specified boundary conditions given by equations A-6 and A-7.

$$\frac{1}{r^2} \frac{\partial}{\partial r} \left(r^2 \frac{\partial c}{\partial r}\right) = \frac{1}{D} \frac{\partial C}{\partial t} \qquad \text{(A-5)}$$

$$\frac{\partial c}{\partial r} = 0 \quad @ \; r = 0 \qquad \text{(A-6)}$$

$$C = f(p_g) \quad @ \; r = a \qquad \text{(A-7)}$$

Equations A-5, A-6, and A-7 describe the diffusion of natural gas in a solid spherical particle where the concentration of gas at the surface of the sphere is a function of the gas pressure in the fractures. Equation A-5 can be solved for the concentration distribution of gas in a sphere, which in turn is used in the computation of the sorption rate given by

$$N_V = \frac{3\ (M.W.)\ D}{r} \left. \frac{\partial c}{\partial r} \right|_a \qquad \text{(A-8)}$$

Crank[32] has shown that the shape of a particle is relatively unimportant in modeling the diffusion process, and that the equation for a sphere adequately describes the flow for many other shapes as well.

Equations A-1 through A-8 describe the dual porosity mathematical model. The solution of these equations was obtained by utilizing the Douglas-Rachford alternating direction implicit procedure (ADIP).

TABLE 1. - Columbia Gas Well No. 20401 - Physical Characteristics

Log Depth[a] feet	Lithology[a] of well	Perforated[a] Interval	Average core k, md	In Situ[a]* k, md	Core Sw, %	Average core Ø %	Average gas content off-gassing cf/cf	Average Gas Content Coriband HC-FT
2400	Base of Berea							
2500 2600	Upper Gray Shale		NA	NA	NA	NA	NA	NA
2700		Zone 4	NA	NA	NA	NA	NA	NA
2800 2900	Upper Brn Shale Middle		NA	NA	NA	NA	NA	NA
3000 3100	Gray Shale	Zone 3	NA	Max/.0635 Min/.0477 Avg/.0556	NA	NA	NA	NA
3200			NA	NA	NA	NA	NA	NA
3300 3400	Middle Brown Shale	Zone 2	NA	Max/.3545 Min/.0637 Avg/.2091	NA	NA	NA	NA
3500 3600 3700	Lower Gray Shale		NA	NA	NA	NA	NA	NA
3800 3900	Lower Brown Shale	Zone 1	NA	Max/.0239 Min/.5810 Avg/.3025	NA	NA	NA	NA

a. Columbia Gas System
b. Battelle Columbus Laboratories
c. Core Laboratories, Inc.
d. Coriband
NA Not Available
* Zones communicated

TABLE 3. - Columbia Gas Well No. 20403 - Physical Characteristics

Log Depth[a] feet	Lithology[a] of Well	Perforated[a] Interval	Average[c] Core k, md	In Situ[a] k, md	Core Sw, % **	Average Core Ø[bc] %	Average Gas Content Off-gassing[a] cf/cf	Average Gas Content[d] Coriband HC-FT
2600	Base of Berea							
2700	Upper Gray Shale		.005	NA	NA	1.67	.02	.0047
2800	Upper Gray Shale	Zone 4	NA	NA	NA	1.18	.02	.0000
2900	Upper Gray Shale		.004	NA	NA	0.94	.05	.0029
3000	Upper Brn Shale		960*					
3100 3200	Middle Gray Shale	Zone 3	NA	NA	NA	0.93	.14	.0045
3300 3400	Middle Gray Shale		NA	NA	NA	0.90	.13	.0027
3500 3600	Middle Brown Shale	Zone 2	.001	Max.=.32 Min.=.04 Avg.=.18	NA	0.62	.26	.0005
3700 3800	Lower Gray Shale		.016	NA	NA	0.62	.35	.0158
3900 4000	Lower Gray Shale Lower Brn Shale	Zone 1	.004	Max.-.10 Min.=.05 Avg.=.08	NA	1.75	.41	.0057
4100	Top Onondaga LS.							

a. Columbia Gas System
b. Battelle Columbus Laboratories
c. Core Laboratories, Inc.
d. Coriband
NA Not Available
* Based on analysis of one sample in Upper Brown Shale
** Average Sw from logs = 55%[28]

TABLE 2. - Columbia Gas Well No. 20402 - Physical Characteristics

Log Depth[a] feet	Lithology[a] of well	Perforated[a] Interval	Average core k md	In Situ[a] k, md	Core Sw, %	Average[a,b] Core Ø %	Average[b,c] gas Content off-gassing cf/cf	Average Gas Content Coriband HC-FT
	Base of Berea							
2600 2700 2800	Upper Gray Shale		NA	NA	NA	2.07	0.02	NA
2900 3000 3100 3200	U.Brn Sh. Middle Gray Shale	Zone 2	NA	NA	NA	1.82	0.21	NA
3300			NA	NA	NA	0.44	0.35	NA
3400 3500 3600 3700 3800 3900	Middle Brown Shale Lower Gray Shale Lower Brn Shale	Zone 1	NA	NA	NA	0.63	0.55	NA
4000 4100	Top of Onondaga Limestone							

a. Columbia Gas System
b. Battelle Columbus Laboratories
c. Core Laboratories, Inc.
d. Coriband
NA Not Available

TABLE 4. - Estimated Gas in Place for Columbia Gas Well No. 20403

Formation	Thickness (ft)	Offgassing, SCF	Offgassing Average SCF/cf	Volumetric, SCF	Porosity, %	Gas Saturation, %
Upper Gray Shale	210	41,164,200	0.03	219,915,984	0.0191	0.45
Upper Brown Shale	50	26,131,000	0.08	21,917,580	0.0079	0.45
Middle Gray Shale	400	313,632,000	0.12	203,303,034	0.0093	0.45
Middle Brown Shale	150	350,836,000	0.36	53,342,373	0.0062	0.45
Lower Gray Shale	380	769,705,000	0.31	270,643,051	0.013	0.45
Lower Brown Shale	100	640,332,000	0.98	46,538,190	0.0085	0.45
TOTAL GAS (SCF)		2,143,800,400		815,660,212		

TABLE 5. - Input Data for the Model

Wellbore radius	0.292 ft
Drainage radius	1600 ft
Reservoir Temperature	575° R
Initial Reservoir Pressure	284 psi
Specific Gravity of Gas	0.62
Average Compressibility Factor	0.96
Shale Bulk Density	2.70 g/cm^3
Initial Gas Concentration	2.84 cm^3/g
Gas Viscosity	0.0125 cp
Formation Thickness	622 ft
Formation Depth	3,720 ft
Porosity	0.02
Permeability	0.10 md
Gas Saturation	0.458
Water Saturation	0.542
Diffusion Coefficient	0.1×10^{-7} cm^2/s
Particle Radius	10 cm
Skin Factor	-3.5
Total Simulation Time	15 years

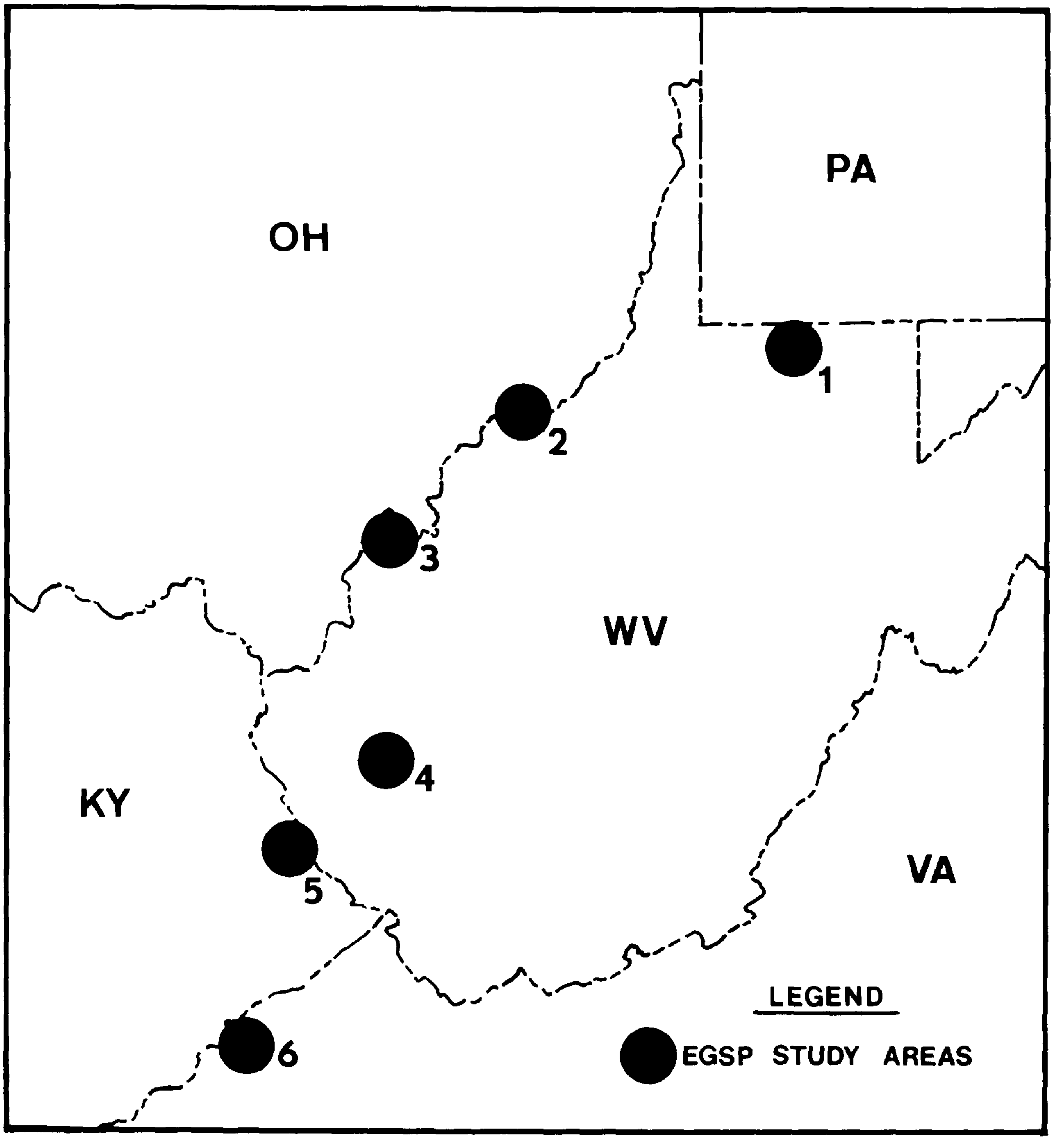


FIGURE 1 – Location Map of EGSP Study Areas

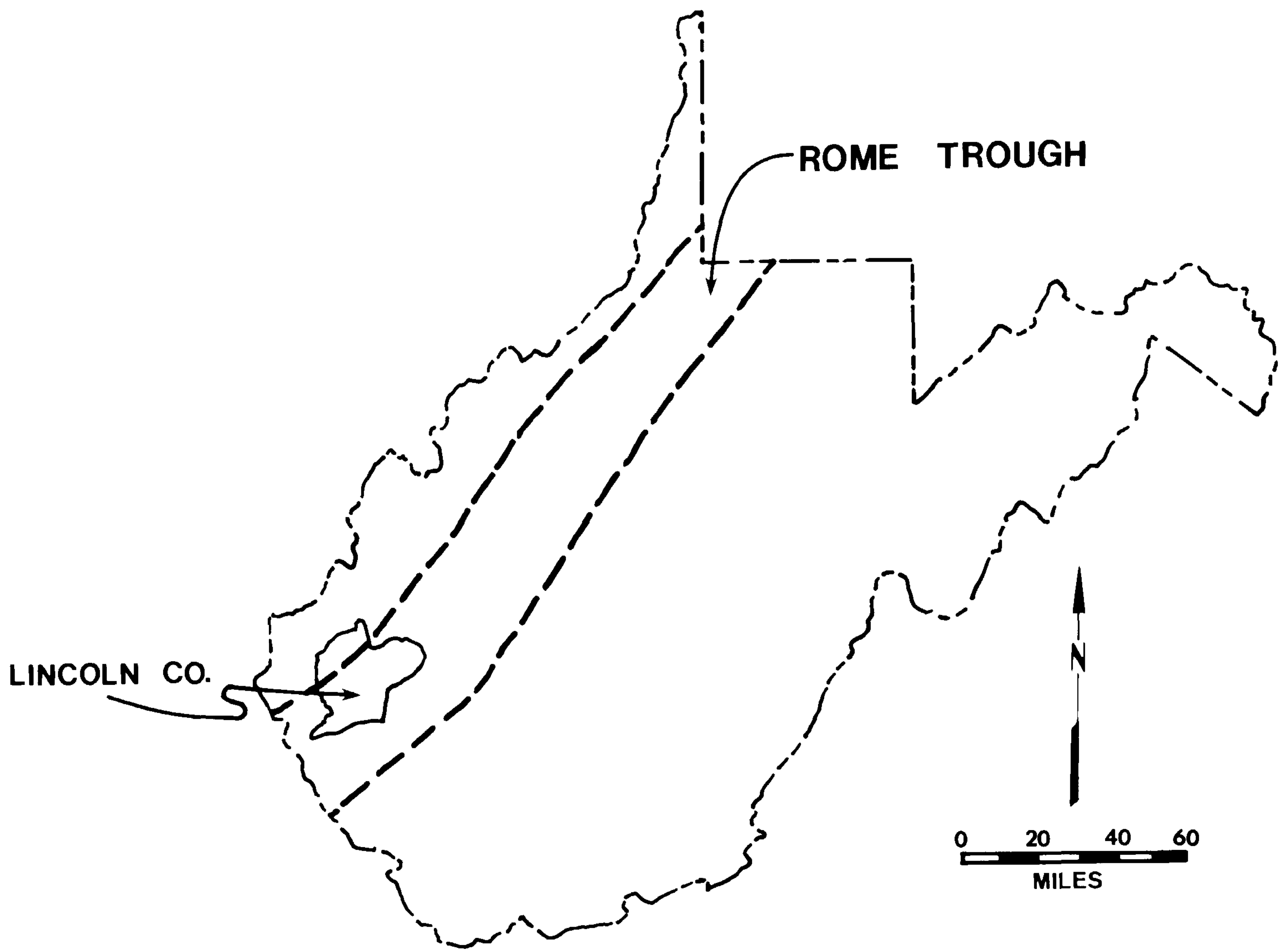


FIGURE 2 – Location of Lincoln Co., WV, with Respect to Approximate Location of Rome Trough / Ref. (Modified after 10)

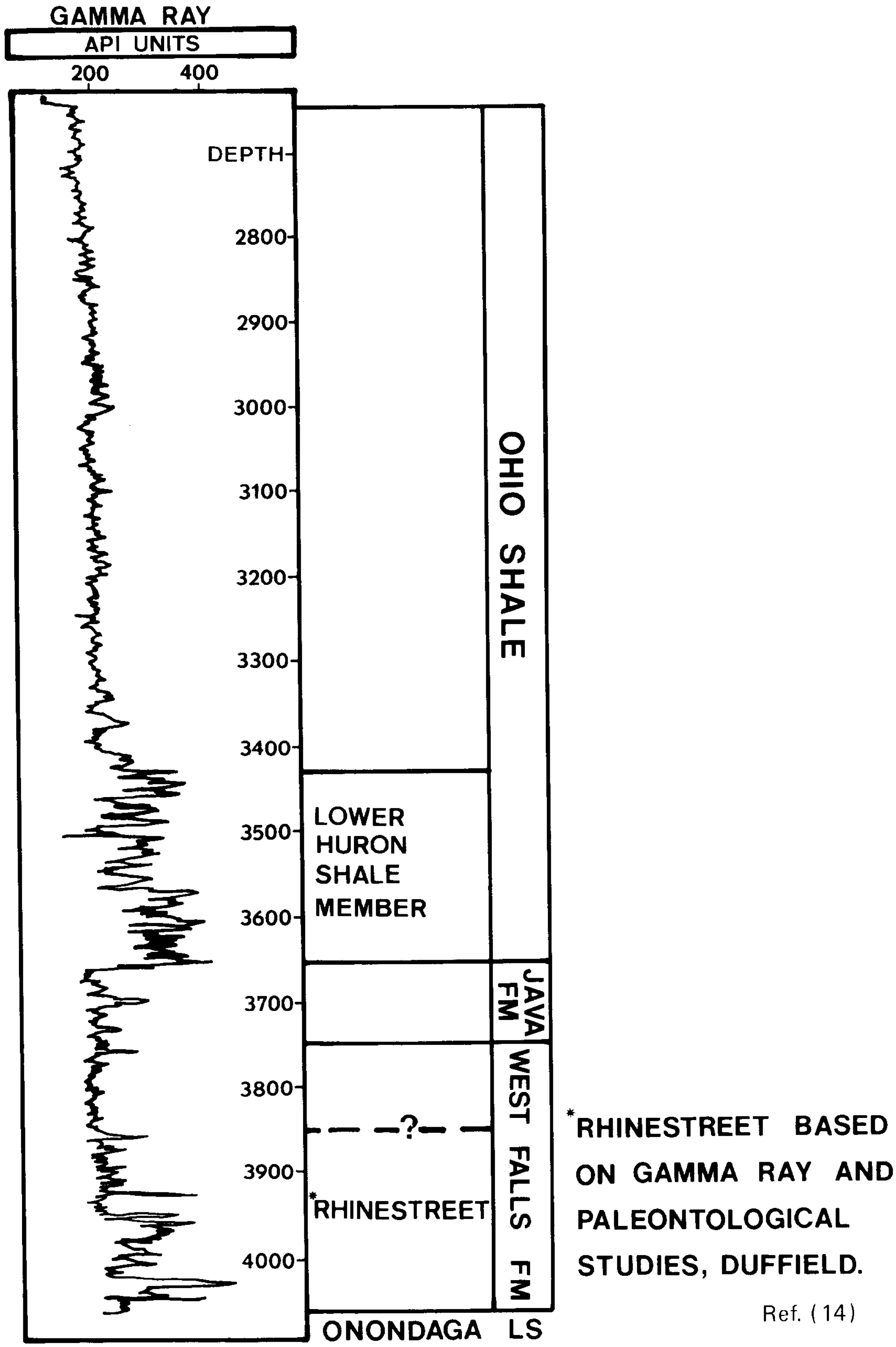
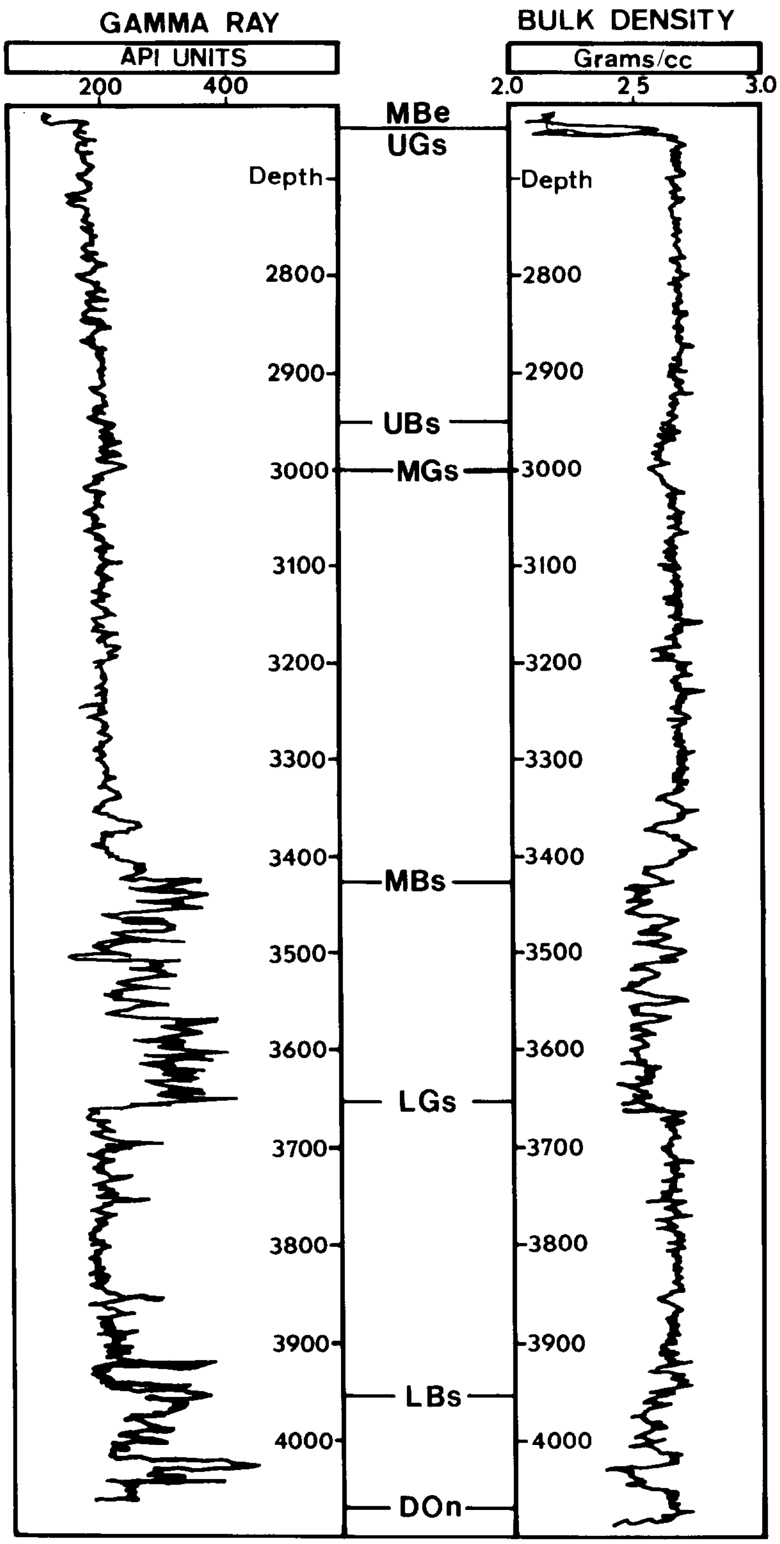


FIGURE 3 – Stratigraphic Column Lincoln Co., WV, Based on Columbia Well No. 20403
Ref. (Modified after 12, 13)



LEGEND

MBe - BASE OF BEREA SANDSTONE

UGs - TOP OF UPPER GRAY SHALE AND SILTSTONE

UBs - TOP OF UPPER BROWN SHALE

MGs TOP OF MIDDLE GRAY SHALE

MBs - TOP OF MIDDLE BROWN SHALE

LGs - TOP OF LOWER GRAY SHALE

LBs - TOP OF LOWER BROWN SHALE

DOn - TOP OF ONONDAGA (CORNIFEROUS) LIMESTONE

FIGURE 4 — Shale Units, Lincoln Co., WV; Based on Columbia Well No. 20403
Ref. (Modified after 12, 15)

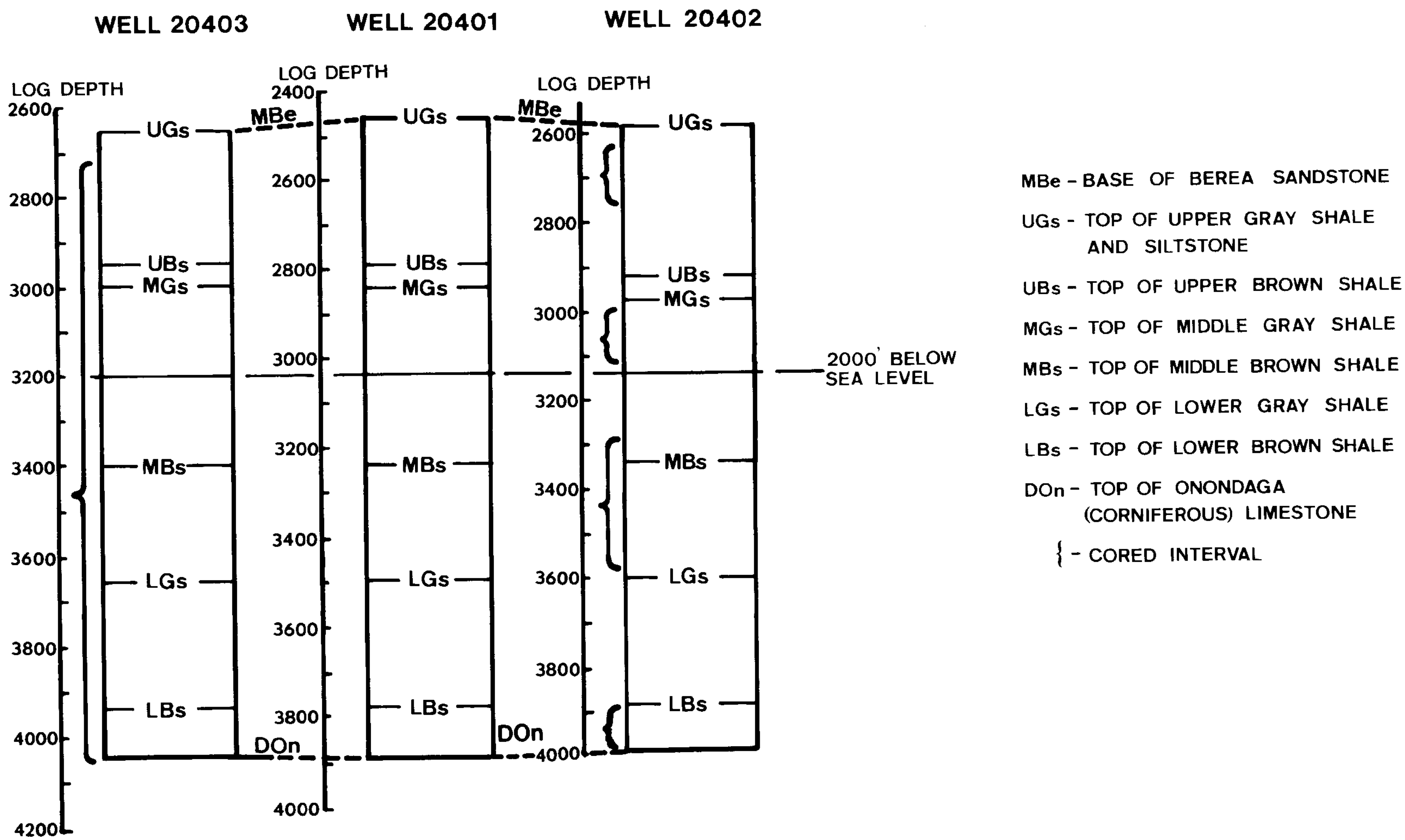


FIGURE 5 – Summary of Geological Findings – Columbia MHF Wells, Lincoln County, WV / Ref. (Modified after 16)

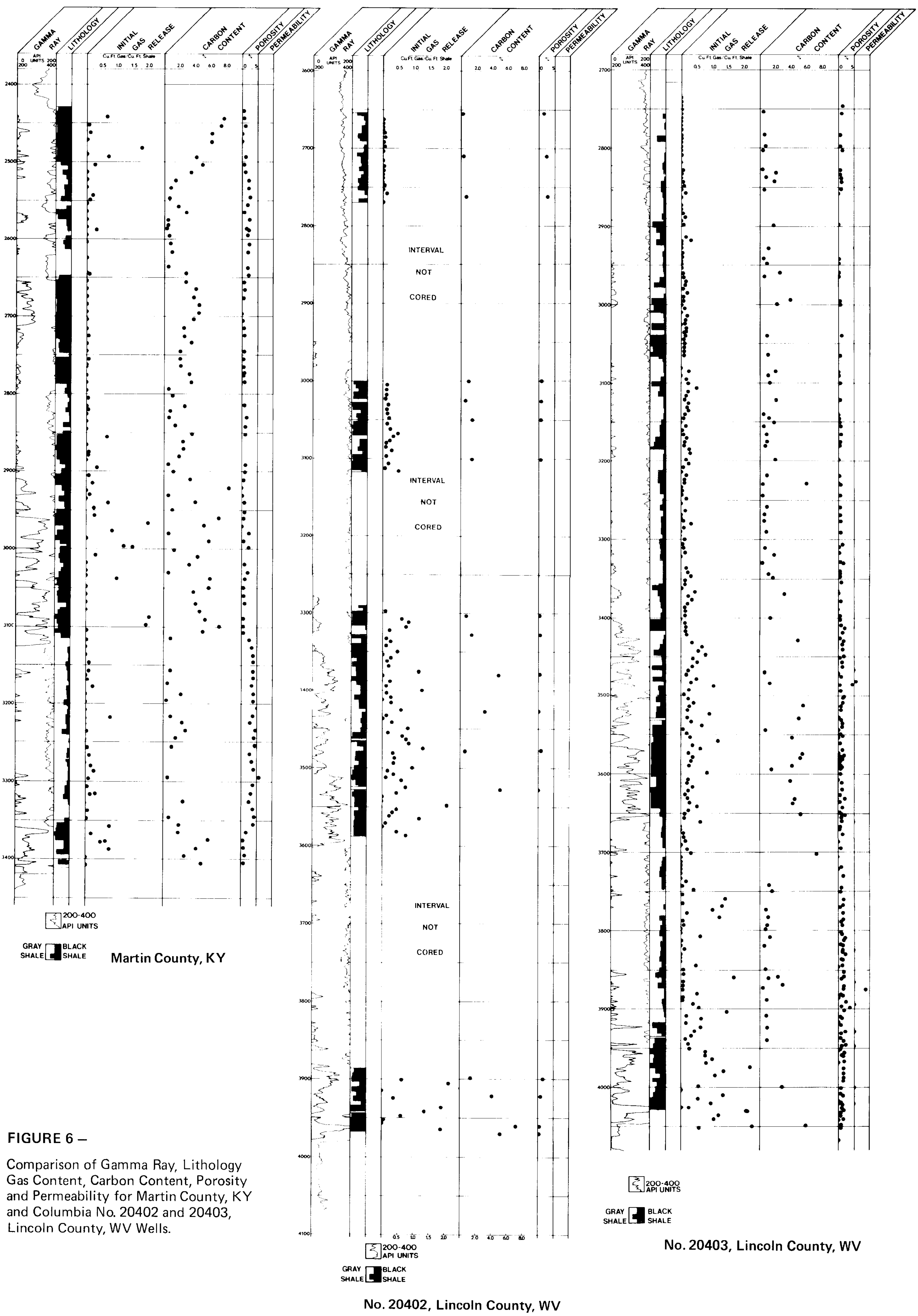


FIGURE 6 –

Comparison of Gamma Ray, Lithology Gas Content, Carbon Content, Porosity and Permeability for Martin County, KY and Columbia No. 20402 and 20403, Lincoln County, WV Wells.

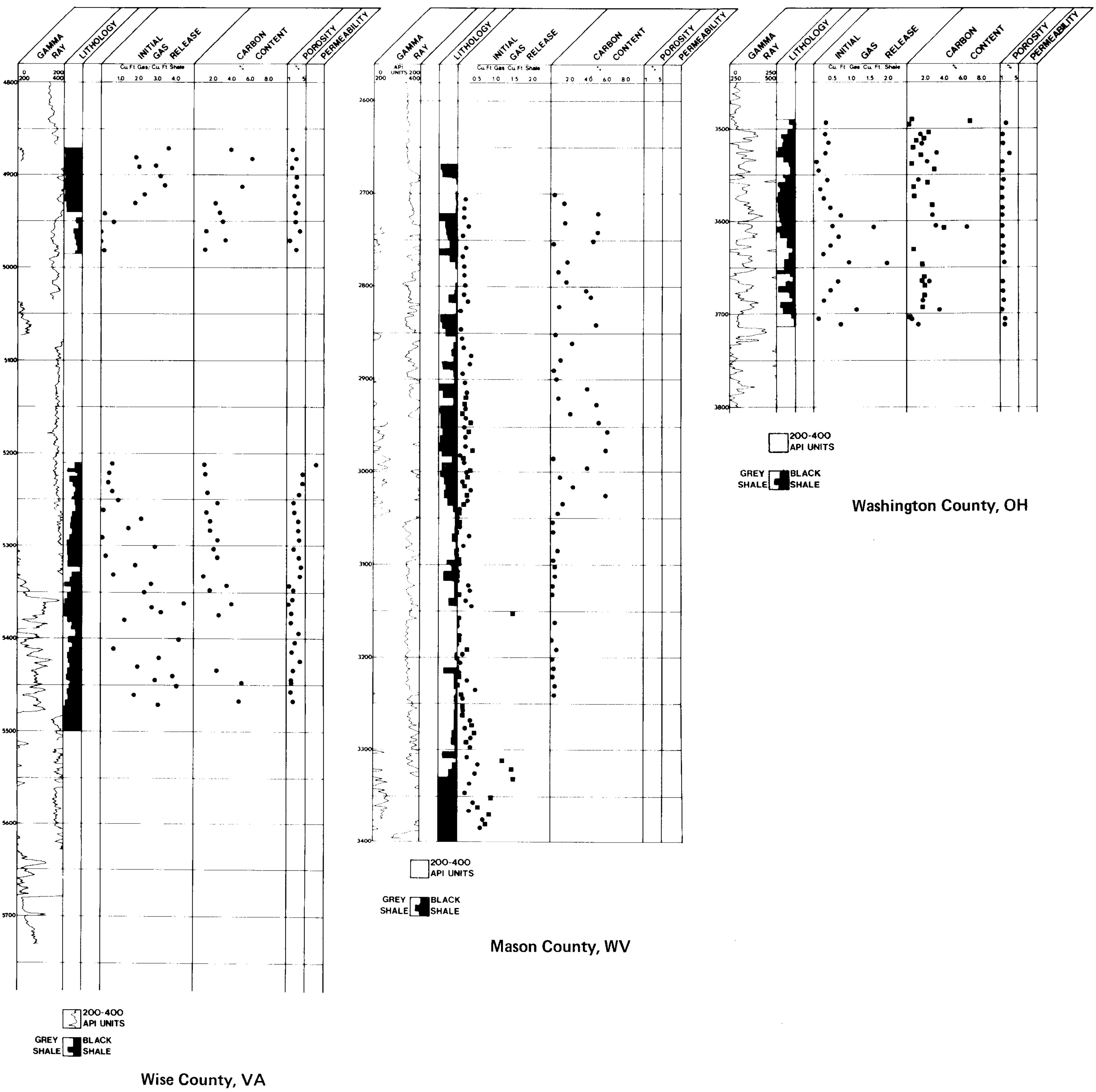


FIGURE 7 — Comparison of Gamma Ray, Lithology, Gas Content, Carbon Content, Porosity, and Permeability for Wise County, VA, Mason County, WV, and Washington County, OH, Wells.

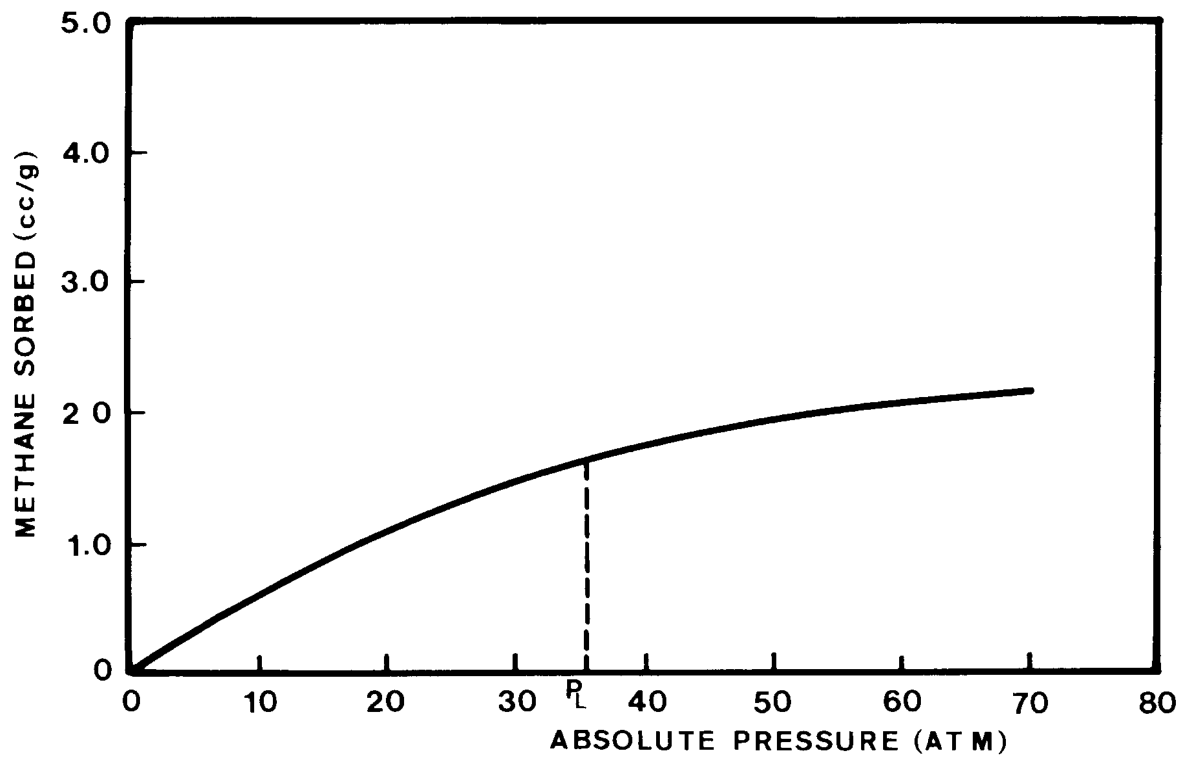


FIGURE 8 — Methane Sorption Isotherm
Ref. (26)

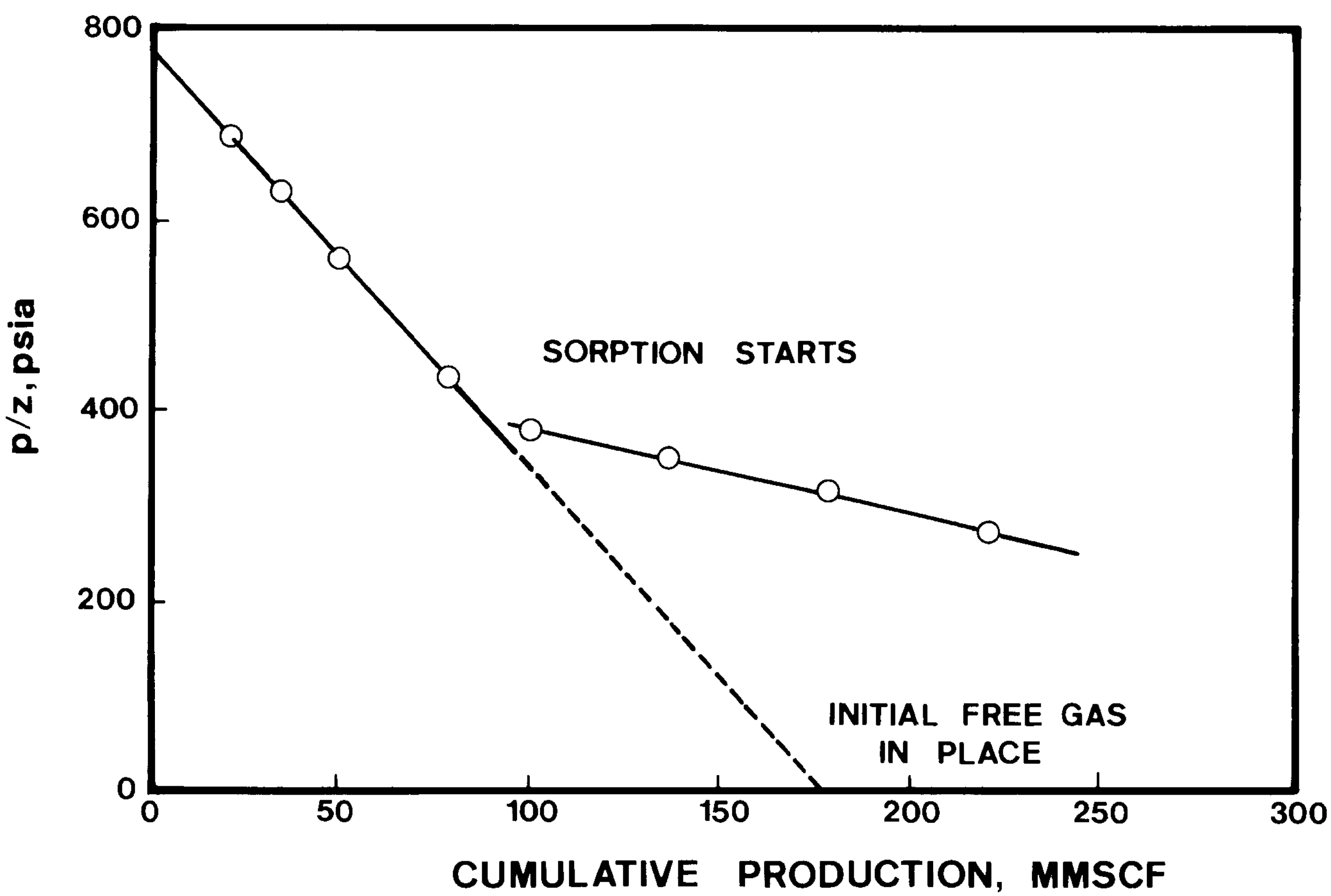


FIGURE 9 – Theoretical Values of p/z Versus Cumulative Production from a Dual Porosity Gas Reservoir

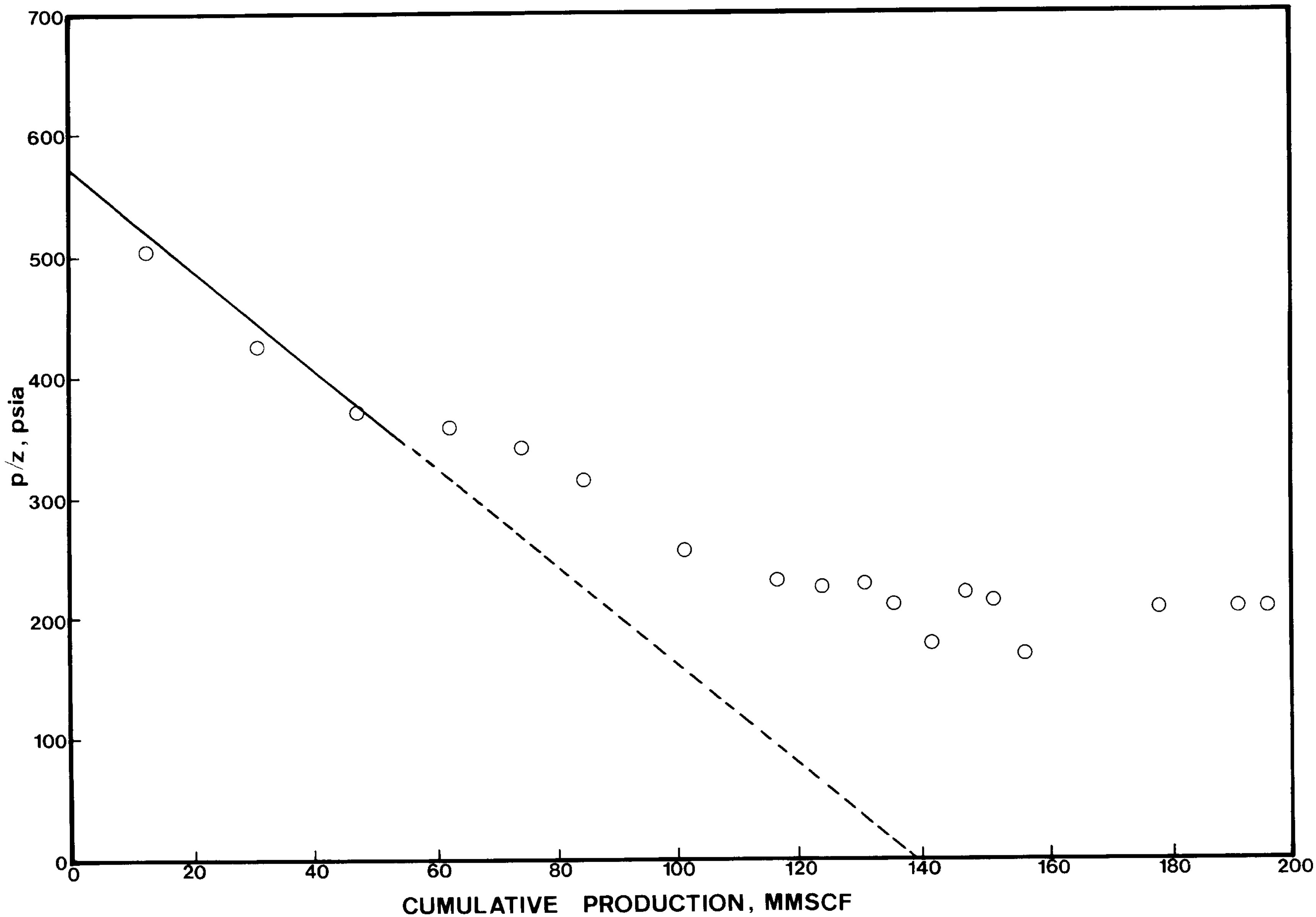


FIGURE 10 — Values of p/z Versus Cumulative Production for Well No. 6630, Lincoln County, WV

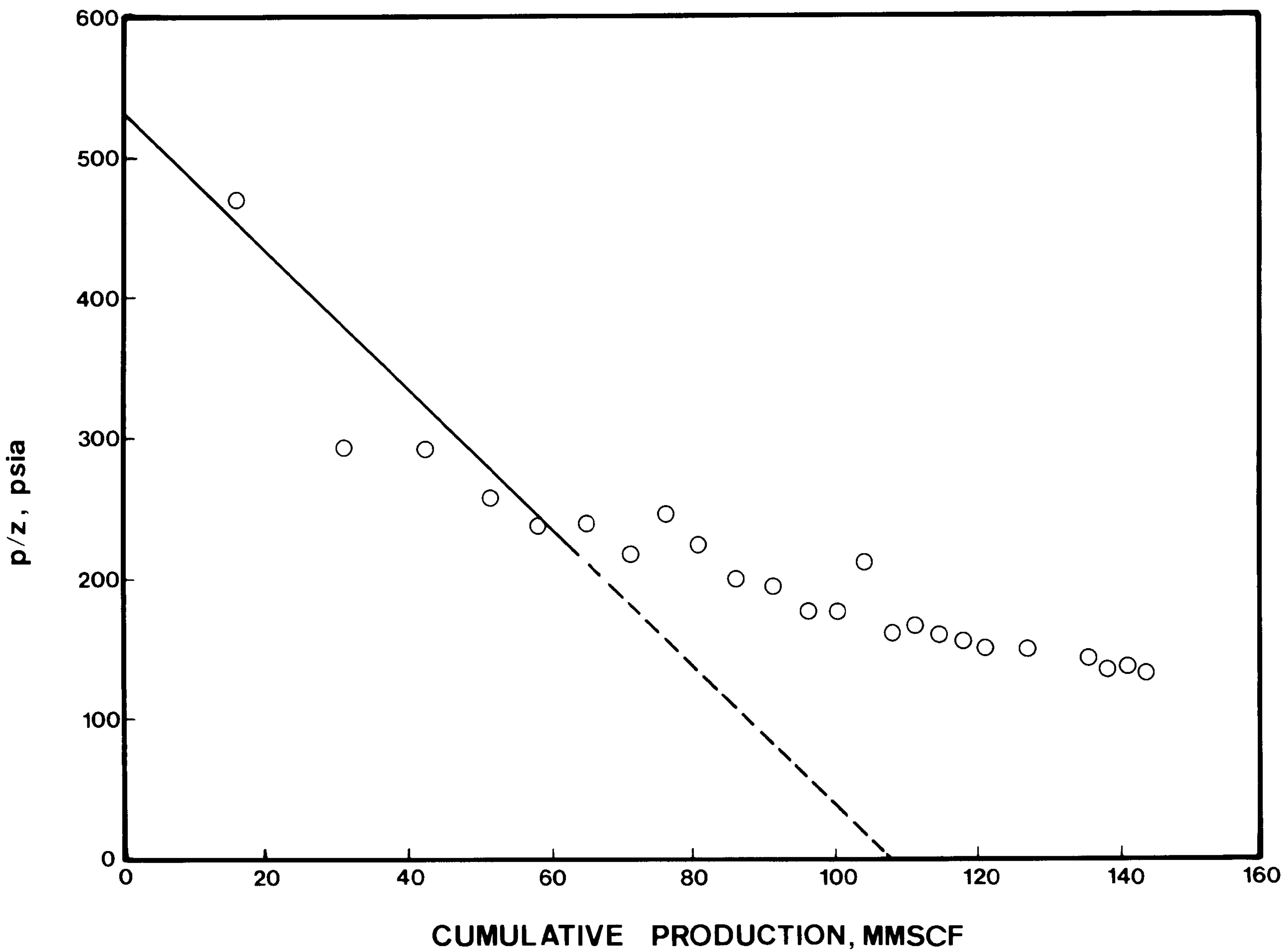


FIGURE 11 – Values of p/z Versus Cumulative Production for Well No. 6654, Lincoln County, WV

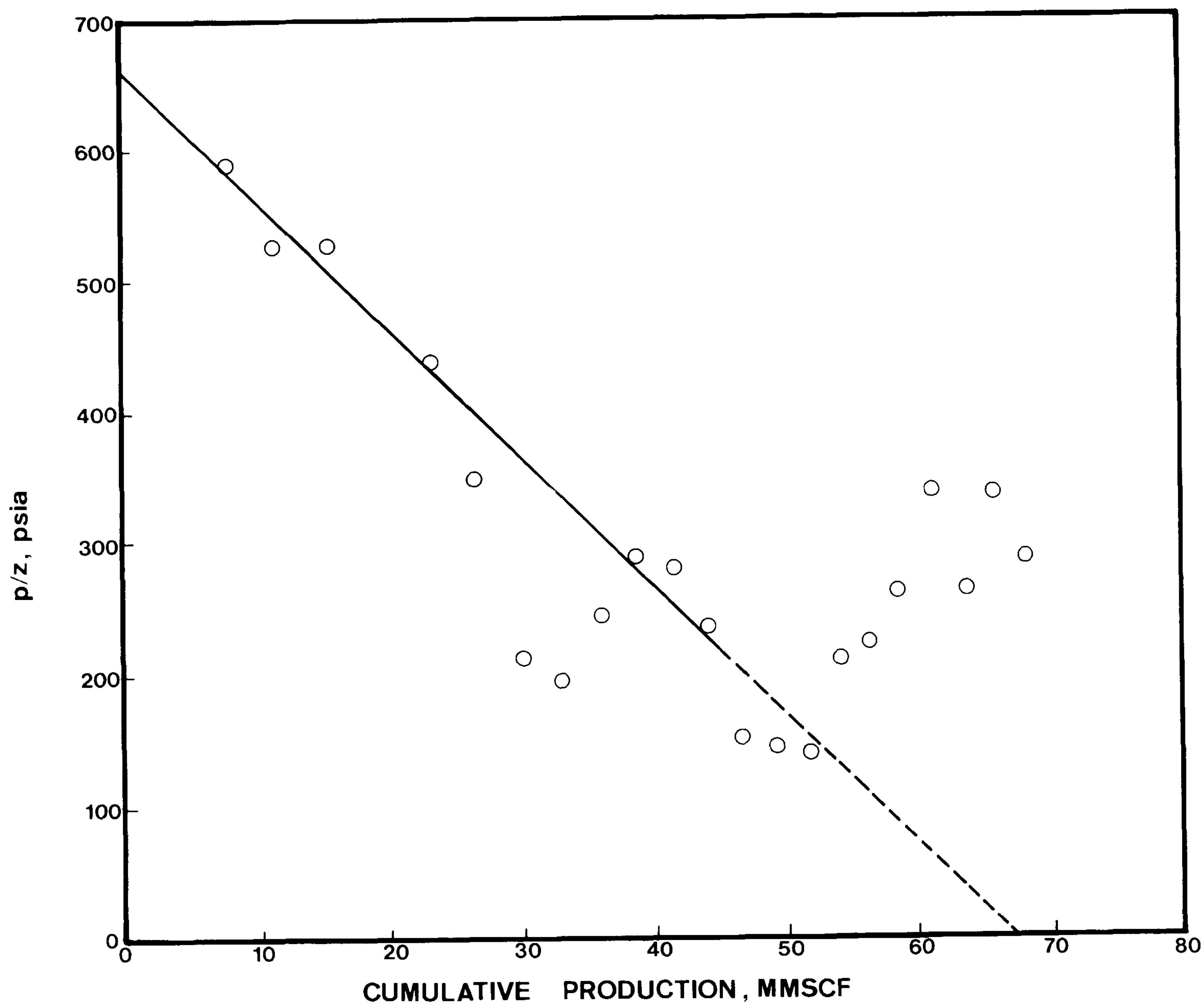


FIGURE 12 – Values of p/z Versus Cumulative Production for Well No. 4121, Meigs County, OH

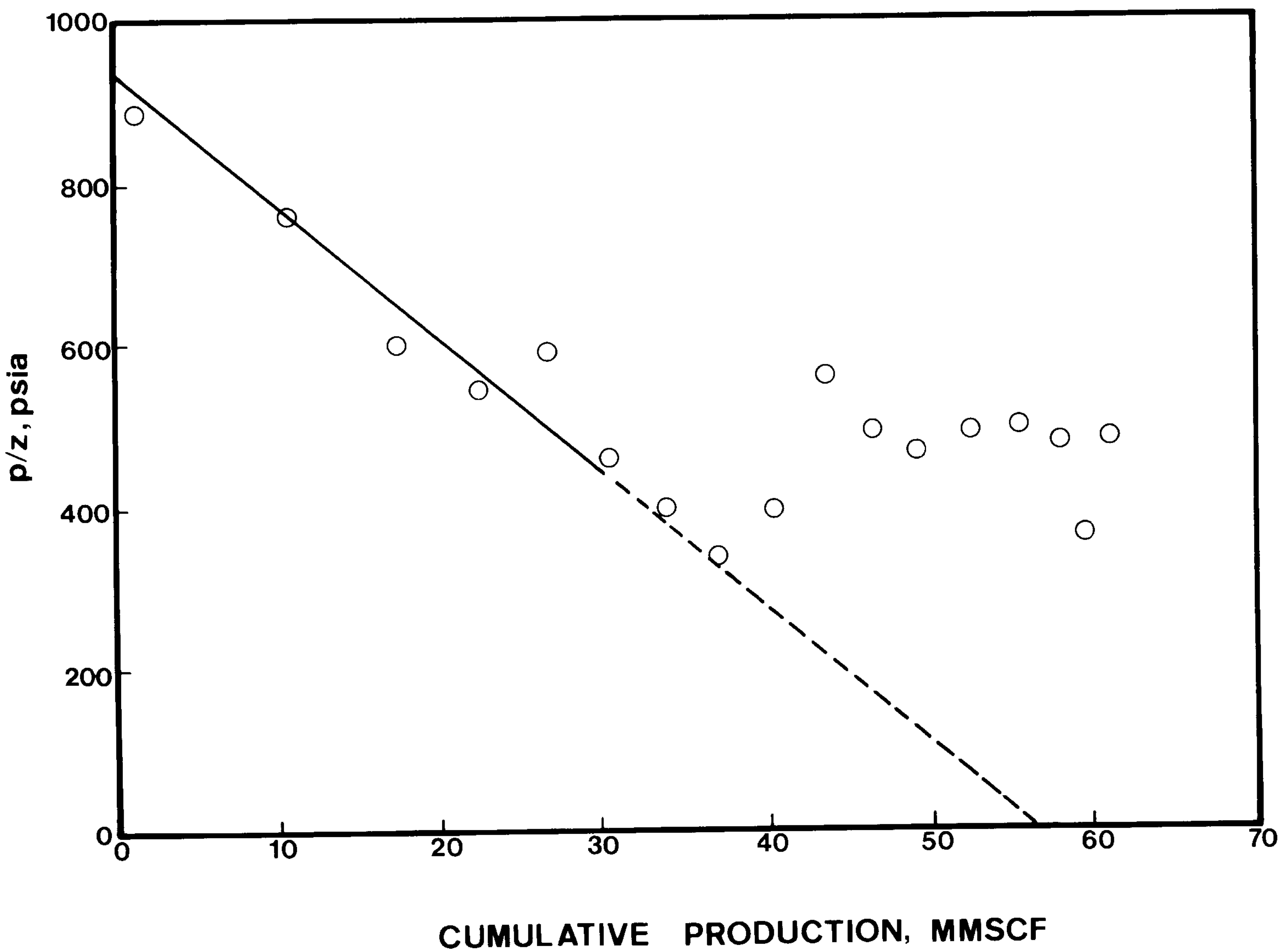


FIGURE 13 – Values of p/z Versus Cumulative Production for Well No. 9553, Meigs County, OH

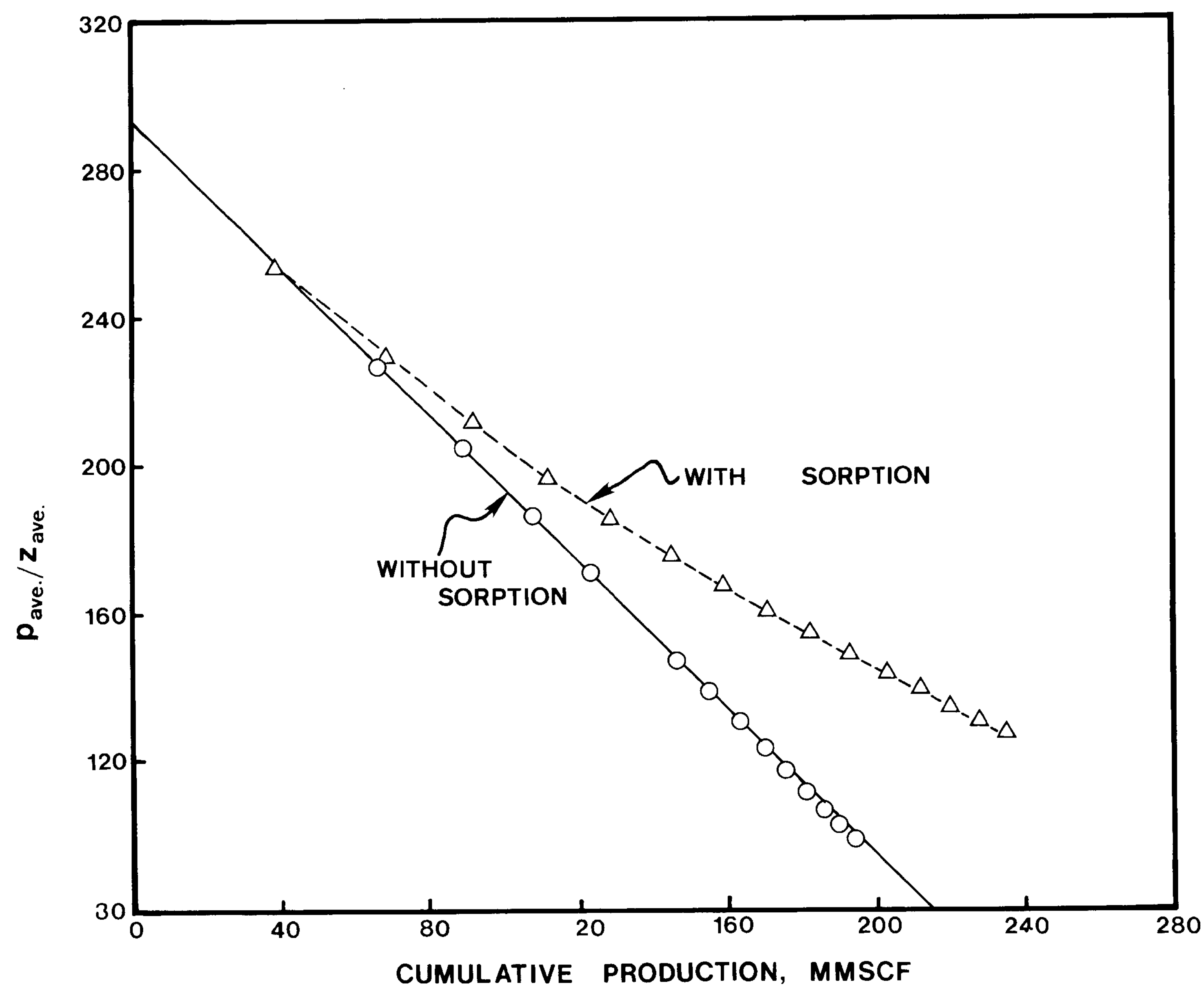


FIGURE 14 – Simulated Values of p/z Versus Cumulative Production for a Dual Porosity Gas Reservoir

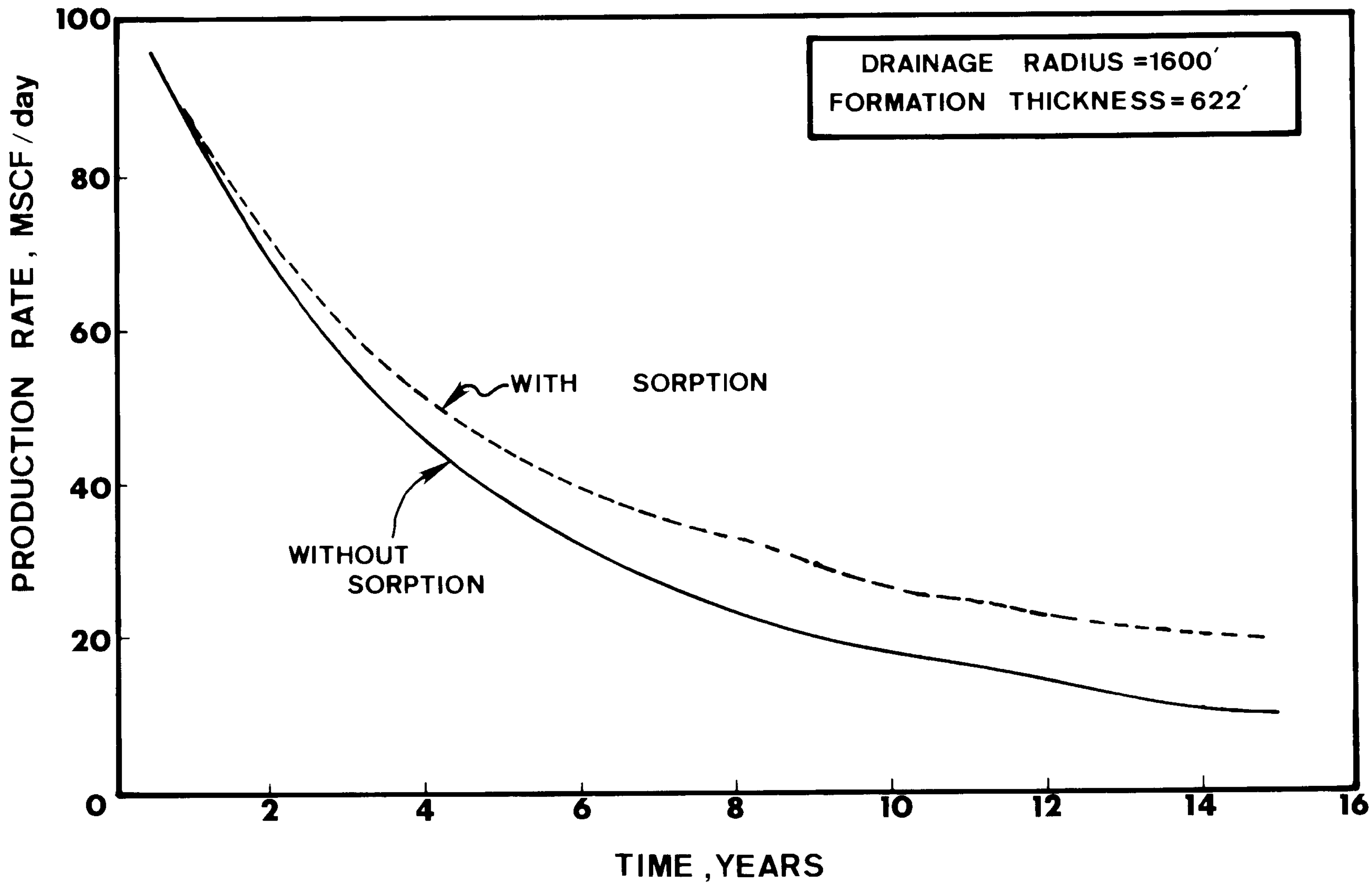


FIGURE 15 – Simulated Values of Production Rate Versus Time for a Dual Porosity Gas Reservoir

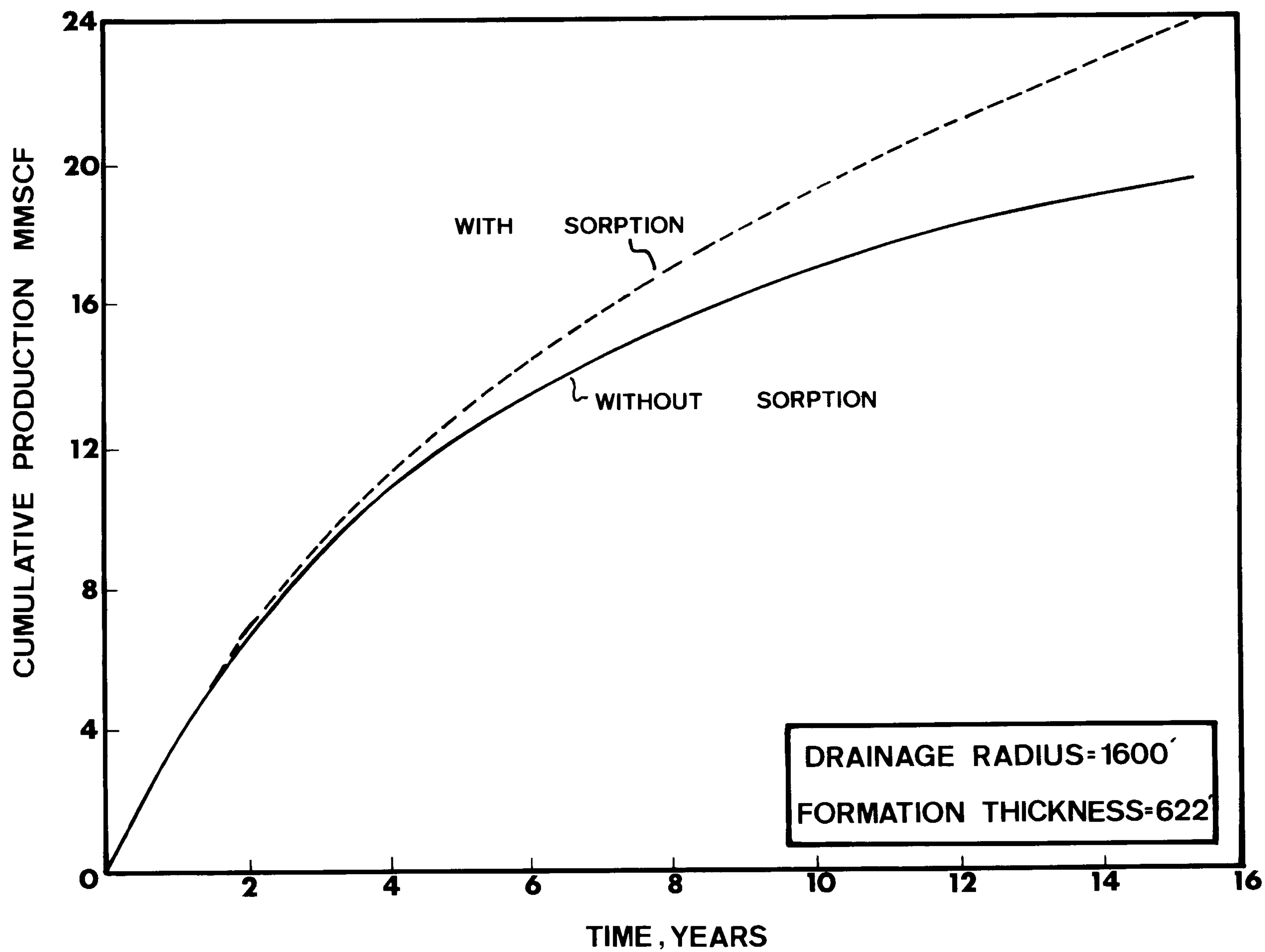


FIGURE 16 — Simulated Values of Cumulative Production Versus Time for a Dual Porosity Gas Reservoir